Nebraska Public Power District
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March 15, 2011

Ms. Shelley Schneider
Air Administrator, Air Quality Division
Nebraska Department of Environmental Quality
Suite 400, The Atrium
1200 N Street
Lincoln, NE 68509-8922

Subject: Nebraska Public Power District, Gerald Gentleman Station, Units 1 & 2, Sutherland, NE Supplemental BART Assessment – Dry Sorbent Injection (DSI) and Dry Sorbent Injection Cost Analysis for Gerald Gentleman Station

Dear Ms. Schneider:

In response to the Nebraska Department of Environmental Quality's (NDEQ) request in the telephone call of February 15, 2011, enclosed is the Supplemental BART Assessment evaluating the potential applicability of Dry Sorbent Injection (DSI) technology for control of sulfur dioxide (SO_2) emissions as part of the Best Available Retrofit Technology (BART) requirements for Gerald Gentleman Station (GGS) Units 1 & 2. This submittal was prepared under severe time constraints due to the need to meet the NDEQ's necessary response date and, therefore, it is not as refined or detailed as the prior analyses of other technologies in NPPD's 2008 BART Analysis Report.

This analysis concludes that DSI is not as cost effective as dry or wet Flue Gas Desulfurization (FGD) on a cost per deciview basis, which is the first reason it should be ruled out as a BART option. The primary component of annualized cost for DSI technology is the relatively high costs of the selected sorbent (Trona). Compounding this is the very high uncertainty in how effective DSI could be on GGS Units 1 & 2. Most of the applications of DSI have been for control of sulfur trioxide (SO_3) emissions and resulting "blue plume" issues, using much lower sorbent injection rates than would be needed to attempt a high level of SO_2 control. Given the lack of implementation of DSI technology on boilers in this size range for SO_2 control, and without prior GGS specific modeling and testing, attempting to use the technology for GGS would truly constitute a demonstration project. This is a second reason why DSI should be ruled out as a BART option.

If you have any questions regarding the enclosed Supplemental BART Assessment, including dispersion modeling, prepared by HDR Engineering, Inc., or the enclosed Dry Sorbent Injection Cost Analysis prepared by Sargent & Lundy, please do not hesitate to contact me at (402-563-5355).

Sincerely,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: BART Analysis of DSI, including dispersion modeling on CD

cc: Mike Linder, NDEQ w/o cd
Jay Ringenberg, NDEQ w/o cd
Brad Reid, NDEQ w/cd

bc: Dave Sloat, Sargent & Lundy w/o cd
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Nebraska Public Power District, Gerald Gentleman Station, Units 1 & 2, Sutherland, NE

Supplemental BART Assessment – Dry Sorbent Injection (DSI)

INTRODUCTION

In February 2011 the Nebraska Department of Environmental Quality (NDEQ) requested that Nebraska Public Power District (NPPD) supplement the 2008 BART Analysis for Gerald Gentleman Station (GGS) Units 1 & 2. The 2008 BART Analysis considered various technologies for the control of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions. The BART determination of NDEQ contained in the December 2010 draft Nebraska Regional Haze SIP is that BART for these emission units is the application of low-NOx burners and overfire air (LNB/OFA) to meet an average (of both units) NO_x emission limit of 0.23 pounds per million British thermal units (lb/MMBtu) of heat input, and continued use of low sulfur coal with respect to SO_2 emissions, without installation of post-combustion controls.

NDEQ has requested that NPPD perform an analysis of DSI in a "side-by-side" comparison against dry and wet flue gas desulfurization (FGD) systems, which were evaluated in the 2008 BART Analysis. Because the possible implementation timing of SO_2 emission control retrofits for any of these technologies would be farther in the future than originally assessed, NPPD requested Sargent & Lundy to perform the cost analysis for a hypothetical implementation of DSI in the year of 2016 (see attached Appendix A, Dry Sorbent Injection Cost Analysis for Gerald Gentleman Station, prepared by Sargent & Lundy, March 11, 2011). Sargent & Lundy has escalated the earlier costs for dry and wet FGD to the year 2016, and also used 2016 for DSI cost estimation, to provide the most reasonable side-by-side comparison of the various control technologies. HDR has used the Sargent & Lundy cost estimates, together with CALPUFF dispersion modeling results for visibility improvement with DSI, to calculate the costs per amount of visibility improvement to allow a comparison of DSI with both dry and wet FGD technologies assessed in the 2008 BART Analysis.

BART ANALYSIS – DRY SORBENT INJECTION

As with the 2008 BART Analysis, and as directed by BART implementation guidelines for control of Regional Haze (Appendix Y to 40 CFR 51), this analysis of DSI proceeds in a five-step process, as follows:

STEP 1—Identify All Available Retrofit Control Technologies,

STEP 2—Eliminate Technically Infeasible Options,

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4—Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

STEP 1—Identify All Available Retrofit Control Technologies

This step is fairly obvious for the current analysis, as NPPD has been asked to assess just one additional control technology for SO_2 emissions control, that being DSI. However, the BART guidelines state that:

> *"In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving."*

This is a challenging aspect of the current DSI evaluation, because the technology has not been applied on similar units such that we can have confidence in knowing what "maximum level of control" to assume for the technology. On the one large boiler proposed for DSI application, a unit rated at 584 MW at the Boardman Power Plant in Oregon, the applicant proposed DSI implementation to bring emissions down from 0.6 lb/MMBtu to 0.4 lb/MMBtu (33% reduction), and requested flexibility to revise the final SO_2 emission rate depending on the success of pilot testing. Also, as discussed in the more detailed technical assessment provided by Sargent & Lundy (see Appendix A), the temperatures in the ductwork where sorbent could be injected on GGS Units 1 & 2 are not optimum, which would make it more difficult to achieve high SO_2 removal rates.

Given the great uncertainty in applying DSI for the first time at a large coal-fired boiler, this analysis has identified a theoretical controlled emission rate of 0.36 lb/MMBtu, which would equate to nearly 80% control for the design basis coal used for the FGD analysis in the 2008 BART Analysis. The 0.36 lb/MMBtu emission rate being assessed here is slightly more aggressive than in the Boardman Power Plant DSI BART Analysis, and for the reasons stated above and in Appendix A, may be quite optimistic given the lack of demonstration of DSI on boilers of this size and type.

By using the emission rate of 0.36 lb/MMBtu for this DSI analysis, NPPD is not committing to this number as a potential permit limit. This is only being used as a potential control level to produce an estimate of the costs and resultant impacts for DSI implementation. Given the uncertainties, it would take a significant amount of GGS-specific facility modeling and testing studies accompanied by enforceable contractual vendor performance guarantees to be confident about meeting any particular emission rate.

STEP 2—Eliminate Technically Infeasible Options

Based on lack of DSI implementation on similar sized PRB-fired coal boilers, NPPD's engineering consultant, Sargent & Lundy considers DSI not "technically feasible" as defined under the BART guidelines. In its discussion of technical feasibility under the BART guidelines, EPA states:

> *Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, we do not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an*

emissions limit is technically infeasible. Generally, you should make decisions about technical feasibility based on chemical, and engineering analyses (as discussed above), in conjunction with information about vendor guarantees.

NPPD does not have a contractual emissions performance guarantee from any vendors of DSI technology. Obviously, such a vendor has much to gain in sorbent sales if their technology is implemented successfully, but also has much to lose if a guarantee cannot be met, and will be reluctant to make such a guarantee without substantial pilot studies on units of similar size and characteristics to the units being considered for controls. Given the fact that DSI for control at any given outlet emission rate has not been demonstrated on a unit similar to GGS Unit 1 & 2, Sargent & Lundy considers DSI to be an undemonstrated technology for these units at this time. However, because of the NDEQ request that NPPD evaluate DSI as if it were a technically feasible control option for GGS, NPPD is carrying the DSI technology evaluation (assuming 0.36 lb/MMBtu outlet SO_2 emissions) through the final three steps of the BART analysis as described below.

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies

In this case, the only additional technology being evaluated is DSI. Step 3 involves evaluating the potential control effectiveness of the technology or technologies being considered. EPA expresses in the BART guidelines that the control level should be specified in a metric that relates to the process rate or product produced, which in the case of boilers is typically specified in units of lb/MMBtu. In this case, we have limited information to provide a basis for establishing a control level as discussed earlier. Thus, to present the comparison requested by NDEQ, and based on both a similar control level used in the Boardman Power Plant DSI BART analysis, and a very aggressive removal rate for GGS, an SO_2 control level of 0.36 lb/MMBtu has been selected for this analysis.

STEP 4—Evaluate Impacts and Document the Results

The fourth step in the BART analysis evaluates A) costs of compliance, B) energy impacts, C) non-air quality environmental impacts, and D) remaining useful life.

With respect to "remaining useful life," this factor is considered only if the source unit(s) being evaluated have a relatively short life until expected permanent shutdown, such that a typical amortization period for control equipment (e.g., 10-20 years) means that BART controls would not be useful for at least a normal amortization period. In this case, both GGS units are expected to have a long enough operating future such that remaining useful life does not affect the BART cost analysis.

In the case of potential DSI application to GGS Units 1 & 2, factors A), B) and C) above have all been assessed by Sargent & Lundy (see Appendix A) in terms of their effects on potential costs to NPPD. The costs of compliance are calculated for both capital expenditures to install the DSI technology and supporting infrastructure (rail spur, sorbent tanks, larger ash/waste handling tanks, landfill, etc.) and for operation and maintenance (O&M) costs. In the case of DSI, the major O&M cost is the sorbent itself, which is estimated to cost $145/ton delivered to the site. A side-by-side summary of the year 2016 annualized capital cost, annualized O&M, and total annualized costs for dry FGD, wet FGD, and DSI are provided in Table 1.

Table 1 also summarizes estimated costs in terms of dollars per ton of pollutant removed. The amounts of pollutants removed are theoretical values based on a 100% capacity factor for both of the units and assuming that the baseline emissions are equal to the maximum 24-hour SO2 emission rate of both units combined in the 2001-2003 period specified by NDEQ for the purpose of ensuring consistent BART analysis across all sources (see 2008 BART Analysis on-file with NDEQ).

Table 1. Comparison of Annualized Costs for SO_2 Emission Controls in 2016 (Combined GGS Units 1 and 2)

Cost Element	Dry FGD	Wet FGD	DSI
Total Capital Cost	$1,057,068,000	$1,109,003,000	$208,330,000
Annualized Capital Cost	$86,166,000	$90,422,000	$17,500,000
Annualized O&M Cost	$30,697,000*	$26,368,000	$138,270,000
Total Annualized Cost	$116,863,000	$116,790,000	$155,770,000
Annual Tons SO_2 Removed	39,815	39,815	25,857
Cost Per Ton Removed	$2,935	$2,933	$6,024

*Includes annual outage cost of $752,000

The energy consumption required by the DSI system is not a large percentage of plant output, so it is not expected to require substantial replacement generation. However, the energy aspect of this analysis tallies only the in-plant energy use, and does not attempt to add up the energy used in mining the sorbent (Trona), transporting it to the facility by rail, land-filling the additional waste product, or obtaining replacement material for the coal ash product currently being consumed for beneficial reuse. The energy costs for off-site Trona production and delivery activities are inherent in the delivered cost of the sorbent at the site.

The non-air environmental impacts are primary due to construction and operation of an additional landfill that would be needed to hold the new waste product. In addition to the Trona-related mass of waste, the ash that is currently sold from GGS would represent not only lost revenue to NPPD, but additional cost for landfill space.

STEP 5—Evaluate Visibility Impacts.

The visibility impacts analysis is based on the same CALMET/CALPUFF modeling system and software version numbers, and the same modeling protocol approved for the 2008 BART Analysis for GGS and other BART-related modeling in Nebraska. HDR executed the CALPUFF model and post-processors for the DSI scenario, assuming baseline emissions of NO_x and PM components, and using an SO_2 emission rate based on an emission factor of 0.36 lb/MMBtu and at maximum permitted heat input rate.

The DSI technology would not be expected to significantly alter stack exhaust parameters, so these were kept the same as for the baseline scenario for input to CALPUFF. An updated table of emission rates and stack parameters with the DSI scenario added is included as Appendix B of this document.

To provide the visibility impact modeling results in a format that is most convenient for NDEQ use, we have copied the tabular summary of SO_2 BART control options and modeling results from Table 10.14 of the draft December 2010 NDEQ State Implementation Plan for Regional Haze and Best Available Retrofit Technology (BART) at the end of this section. We have edited that table to insert the DSI control option and the CALPUFF modeling results. We have also calculated the cost benefit metric in units of dollars/year/change in deciviews ($/yr/ΔdV). All the edits to Table 10.14 for addition of the DSI option and for clarifying the data are shown in gray highlights in the edited table and its footnotes provided at the end of this section.

Both NPPD and HDR are not clear on how the NDEQ has calculated the "Cost per Day of Improvement" metric in Table 10.14 of the draft SIP, so we have left this blank.

The average (across three years of modeled meteorology) cost/benefit metric, or cost effectiveness measured as $/yr/Δdv, is presented in Table 2 for dry sorbent injection (DSI) of Trona with SO_2 controlled to 0.36 lb/MMBtu, and for the two controlled emission levels (0.15 lb/MMBtu and 0.10 lb/MMBtu) with wet flue gas desulfurization (FGD), updated to year 2016 annualized costs. Note that the estimated annualized costs for dry FGD are virtually the same as for wet FGD at the same control levels, so just the wet FGD values are presented here.

Table 2. Average Cost Effectiveness Comparison for SO_2 Controls

Control Technology	Controlled Emissions Level (lb/MMBtu)	Average Incremental Impairment Improvement Cost ($/yr/ΔdV)
DSI	0.36	$ 287,764,058
FGD (wet)	0.15	$ 154,504,368
FGD (wet)	0.10	$ 142,860,500

Table 10.14: Incremental Visibility Effectiveness (SO_2 Controls)

Control Option	Class I Area with Greatest Impact from GGS	2001 Badlands	2002 Badlands	2003 Badlands
Baseline (no SO_2 Control)	SO_2 Modeled Emission Rate (lb/MMBtu)	0.749	0.749	0.749
	Modeled 98th Percentile Value (dV)	2.845	2.828	3.121
	Number of Days Exceeding 0.5 dV	54	55	60
DSI Control Added (0.36 lb/MMBtu)	Modeled 98th Percentile Value (dV)	2.158	2.409	2.540
	Incremental Visibility Impairment Improvement (ΔdV) [1]	0.696	0.419	0.581
	Number of Days Exceeding 0.5 dV	43	44	44
	Incremental Impairment Improvement Cost ($/yr/$\Delta$dV)[1],[3]	$223,807,472	$371,766,110	$268,106,713
	Cost per Day of Improvement			
FGD Control Added (0.15 lb/MMBtu)	Modeled 98th Percentile Value (dV)	1.836	2.125	2.478
	Incremental Visibility Impairment Improvement (ΔdV) [1], [4]	1.009	0.703	0.643
	Number of Days Exceeding 0.5 dV	36	35	39
	Incremental Impairment Improvement Cost ($/yr/$\Delta$dV)[1]	$115,748,266	$166,130,868	$181,633,971
	Cost per Day of Improvement	$3,442,603	$3,543,963	$3,177,787
FGD Control Added (0.10 lb/MMBtu)	Modeled 98th Percentile Value (dV)	1.790	2.026	2.443
	Incremental Visibility Impairment Improvement (ΔdV) [1], [4]	1.055	0.802	0.678
	Number of Days Exceeding 0.5 dV	33	33	36
	Incremental Impairment Improvement Cost ($/yr/$\Delta$dV)[1],[2]	$110,701,422	$145,623,441	$172,256,637
	Cost per Day of Improvement	$3,755,566	$3,755,566	$3,442,603

[1] Total annualized cost & incremental visibility impairment improvement compared to baseline.

[2] The control can be achieved without additional costs, so total annualized cost/the overall incremental impairment improvement is calculated.

[3] Total annualized cost (capital + O&M) of DSI estimated at $155,770,000.

[4]Total annualized costs (capital + O&M) of FGD ("wet" shown here) control options were updated to year 2016 annualized values to calculate the "Incremental Impairment Improvement Cost" for each year of modeling. This cost is estimated at $116,790,000/yr for both wet FGD at 0.15 lb/MMBtu and wet FGD at 0.10 lb/MMBtu (difference is insignificant). Therefore, the annualized cost for the 0.15 lb/MMBtu wet FGD option is conservatively used in the calculations for both the 0.15 and 0.10 lb/MMBtu FGD options.

CONCLUSIONS

Based on the side-by-side comparison of SO_2 emission control with DSI technology to both dry and wet FGD, which were analyzed in the 2008 BART Analysis for GGS Units 1 & 2, it is clear that DSI has substantially higher costs per amount of visibility improvement. Added to this is the great uncertainty in the ability of DSI to remove SO_2 emissions at any specified control level, and it is concluded that DSI can not be considered as BART for GGS Units 1 & 2.